To be placed in Dockets for these proceedings

ATTACHMENT A

Documentation for Emission Default Factors in Joint Staff Proposal for an Electricity Retail Provider GHG Reporting Protocol R.06-04-009 and Docket 07-OIIP-01

Process Used to Determine Default Out-of-State Emissions factors

This document provides a description of the process used to compute some of the numbers in Tables ES-1, Table 1 and the data shown on page 25, all of which is reproduced below to facilitate understanding of this computation documentation. Computations described below apply to the values shown in bold below.

Table ES-1 & Table 1. Summary of Recommended Emission Factors (from page 16)

TYPE OF PURCHASE	RESOURCE TYPE	CO2 EMISSION FACTOR (LBS/MWH)
1. In-state Specified source	All fuels	Use emission factor source has provided to ARB for certification
2. Out-of-State specific source, includes ownership shares and contracts	Mostly coal, some renewables and gas	Calculate emission factor based on ARB methods. Coal factor range is 2017 - 2263
3. CAISO real time energy pool	Balancing energy *Mostly gas and hydro*	Use default factor of 900
4. CAISO Integrated Forward Market (pool)	All fuels, both in and out of state	Use default factor of 1000 lbs/MWh
5. Other in-state unspecified sources	Unknown,	Use default factor of 1000 lbs/MWh
6. Out-of-state specified sellers (system purchase from asset-owning entity	Depends on seller	Request seller to obtain system average certification from ARB, net of resources claimed to serve native load
7. Northwest unspecified marginal generation	69% carbon-free, mostly hydro	Use default rate of **419** lbs/MWh
8. Southwest unspecified marginal generation	90% gas, 10% coal	Use default rate of **1,075** lbs/MWh

Note: Values in lines 7 and 8 <u>include</u> transmission losses

9. C. Regional fuel type averages (2005, EIA 906 form, + 7 ½% for transmission losses)

Natural gas	CA: **1,014**	NW **982**	SW **1,022**
Coal		NW **2,307**	SW **2,355**

Overview of General Methodology

The emissions factors used to estimate greenhouse gas (GHG) emissions from fossil fuels used to generate electricity that is imported into California were developed for natural gas and coal-fired power plants located in the Pacific Southwest (PSW) and Pacific Northwest (PNW) regions, for a total of four emissions factors. Each was determined for 2005 using the following steps:

1. Obtain data for 2005 from EIA Form 906 data for all 50 states from: [http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html]
2. Select the following states for PSW:
    a. Nevada
    b. Arizona
    c. New Mexico
    d. Utah
3. Select the following states for PNW:
    a. Oregon
    b. Washington
    c. Idaho
    d. Montana (western portion; see footnotes for specific facilities)
    e. Colorado (western portion; see footnotes for specific facilities)
4. Remove the amount of generation and fuel use attributed already to California specific purchases due to ownership or contracts for the following coal facilities:
    a. Intermountain Power plant (96% California operations)
    b. Mohave (65.9% California operations)
    c. Four Corners (34.5% California operations)
    d. Navajo (21.2% California operations)
    e. Reid Garner (29.8% California operations)
    f. San Juan (21.4% California operations)
    g. Boardman (16.0% California operations)
5. Sum up all fuel used and MWh produced from natural gas facilities in PSW[1] and then multiply by 31.9[2] x .995[3] x 0.9072[4] x 44/12[5] and convert to million. Result is million metric tons of carbon dioxide generated from all PSW natural gas plants. Divide this result by the sum of MWh to get **0.431** metric tons per MWh. Multiply by 2000/0.9072 to get **951** lbs per MWh. These emissions factors are

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[1] Includes most of New Mexico's natural gas facilities, but not all because some are not considered to be in the PSW region. Specifically, the analysis included natural gas emissions from Esclante, Four Corners (when fired on natural gas), Rio Grande, Maddox, Reeves, Carlsbad, Cunningham, Animas, Raton, Lordsburg, Pyramid, Southside Water Reclamation, University of New Mexico Cogen, Ciniza Refinery, Williams Field Services Kutz Plant, Hidalgo Smelter, Blanco Compressor Station, Chino Mines, Phelps Dodge Tyrone, Milagro Cogen Plant, New Mexico State University, Delta Person, and Afton Generating Station.

[2] This is the emissions factor for natural gas combustion, 31.9 lbs C per million BTU of fuel use. Value comes from Introduction to Estimating Greenhouse Gas Emissions, State and Local Climate Change Program, US EPA, Emissions Inventory Improvement Program, prepared by ICF Consulting.

[3] This is the percent of fuel that volatalizzes to become a gas, from the same reference as Note 2.

[4] This term converts from short tons to metric tons.

[5] This term converts from carbon to carbon dioxide (molecular weights of each).

used for non-specified (i.e., non firm) natural gas-based energy imported to California from the PSW.

6. Repeat Step 5 for all coal plants in PSW[6], including the non-California portion of 4a through 4f above. In this calculation, multiply by 56,378 x .99 x 0.9072 x 44/12 rather than the values used above in Step 5. Result is **0.994** metric tons per MWh or **2,190** lbs per MWh for non-specified coal-based energy imported to California from the PSW.
7. Repeat Step 5 for all natural gas plants in PNW[7]. Result is **0.414** metric tons per MWh or **914** lbs per MWh for non-specified (i.e., non firm) natural gas-based energy imported to California from the PNW.
8. Repeat Step 6 for all coal plants in PNW[8], including the non-California portion of Boardman. Result is **0.973** metric tons per MWh or **2,146** lbs per MWh for non-specified coal-based energy imported to California from the PNW.

Note that the emissions factors do not yet include an adjustment for T&D losses. These are incorporated below. This same approach was used to obtain coal facility emissions factors for specific facilities with the range or results shown in Table ES-1 and Table 1 (2,017 to 2,263 lbs/MWh, not yet adjusted fro T&D losses).

<u>Lines 7 and 8</u>

Table ES-1 and Table 1 show default marginal regional emissions factors of **419** for the Northwest and **1,075** for the Southwest. These values were each determined by using the emissions factors developed above and applying them to the GWh for each unspecified fuel type, as described below.

For the 2005 year example, total energy attributed to unspecified sources is documented in the "Revised Methodology to Estimate the Generation Resource Mix of California's Electricity "presented at the April 12, 2007 workshop. Unspecified imported resources were estimated to be:

Region	Natural Gas GWh	Coal GWh	Carbon-free GWh	Total GWh
Northwest	3,945	1,572	12,365	17,882
Southwest	17,360	723	0	18,083

The following is a sample calculation for the Northwest:

[6] Includes the following coal facilities in New Mexico: Escalante, Raton, Four Corners (non-California portion) and San Juan (non-California portion).
[7] Includes the following natural gas facilities in Montana, which is only partially within the PNW: Glendive, Miles City, JE Corette Plant, and Stone Container Missoula Mill. Also includes the following natural gas facilities in Colorado: Fruta and Rifle.
[8] Includes the following coal facilities in Montana: JE Corette and a "state fuel increment" to account for non-reporting facilities. Also includes the following coal facilities in Colorado: Cameo, Craig, Haden and Nuclea.

Parameter	Value	Operation	Result
Unspecified coal GWH from PNW	1,572 GWH	1572 x .973 tons coal/MWH x 1.075 (T & D losses) /1000 =	1.64 million metric tons CO_2
Unspecified natural gas GWH from PNW	3,945 GWH	3945 x .414 tons natural gas/MWH x 1.075 (T&D losses) / 1000 =	1.76 million metric tons CO_2
Total Unspecified emissions from PNW		1.64 + 1.76 =	3.40 million metric tons CO_2
Compute lbs/MWH		(3,400,000 x 2000/.9072)/(17882 x 1000) GWH =	**419** lbs/MWh

A similar calculation was made for the Southwest to get the **1,075** lbs/MWh result for that region for Table ES-1 and Table 1. Since only coal and natural gas are associated with anthropogenic carbon dioxide emissions, the GWhs for each of these two fuels were multiplied by their respective emissions factors, and the sum of these were divided by the total out of state GWH from the region to get the default rates shown in the tables. The computation includes a "1.075" term to account for transmission and distribution losses.

Line 9, input to Lines 3, 4, and 5

The same basic approach was used to obtain values for Line 9 on page 1. The California emissions factor for natural gas was obtained by summing emissions for all natural gas fired power plants located in California and then dividing by the reported GWh to obtain a result of **1,014** lbs/MWh. These facilities include utility-owned facilities as well as independent power plants and combined heat and power facilities. It was not necessary or appropriate to adjust results for transmission and distribution losses because the total facility's emissions were included, and they include these losses already.

The value for natural gas from the Northwst (**982** lbs/MWh) was obtained by multiplying the result of Step 7 by 1.075 to account for an assumed 7.5 percent transmission and distribution loss and the value for coal from the PNW was likewise multiplied by 1.075 to get the result for coal, **2,307** lbs/MWh.

The values for the Southwest for natural gas (**1,022** lbs/MWh) and for coal (**2,355** lbs/MWh) were also obtained by adjusting by the assumed transmission and distribution loss factor of 7.5 percent.

Some remaining issues for treatment of transmission losses:

1. The statewide control totals for GWhs of imports and exports are actual power flows measured at the border of the balancing authority. Hence, some losses have already

occurred and some are yet to occur. Our draft counting conventions have not addressed this.
2. The 7.5% transmission loss factor was one we have used in other studies and was not developed for Retail Provider purchases over specified paths. Greater specificity to the characteristics of individual transaction may be appropriate.
3. Since the goal is accounting for the responsibility of emissions, we want to count the total energy produced on site.
4. In-state and out-of-state units should be treated the same and in-state power plants already have their T&D losses accounted for by the method used to calculate their GHG emissions.

For further detail on these emission factor calculations, contact: Gerry Bemis, CEC

(END OF ATTACHMENT A)